

APPENDIX A



Sargent & Lundy^{LLC}

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March 11, 2011
Project No. 12681-002

Dry Sorbent Injection Cost Analysis for
Gerald Gentleman Station

Mr. Joseph L. Citta, Jr.
Corporate Environmental Manager
Nebraska Public Power District
1414 15th Street, P. O. Box 499
Columbus, NE 68601

Dear Joe:

As stated in my previous letter (January 6, 2011), it remains S&L's judgment that the DSI technology has not been proven on any power plant the size of the GGS units and, therefore, should not be considered "technically feasible" as the term is defined in the Regional Haze rule. Even so, as requested by NPPD, S&L developed the cost estimates for the application of the DSI technology on both GGS units to be as close to a side-by-side comparison to the previously analyzed dry and wet FGD technologies as is practical and reasonable.

Although the initial capital requirement for a DSI system at GGS is considerably less than that required for either of the FGD technologies evaluated in the 2008 BART Analysis, the operating costs for the DSI system at GGS, over the 20 year amortization life, resulted in an annualized cost of nearly 34% greater for the DSI system. Also, the cost to capture a ton of SO₂ with the DSI system is over twice as expensive as that required with either of the FGD technologies evaluated in the 2008 BART Analysis.

The report with the subject title is attached.

Yours very truly,



William DePriest
Senior Vice President and
Director, Environmental Services

WD/jvk
Attachment
Copies:
J. M. Meacham
P. Hoornaert
D. G. Sloat

Dry Sorbent Injection Cost Analysis for Gerald Gentleman Station**1.0 Introduction**

Gerald Gentleman Station (GGS) is a source subject to the Regional Haze rule. A Best Available Retrofit Technology (BART) Analysis was submitted to the Nebraska Department of Environmental Quality (NDEQ) in February 2008 (hereafter referred to as 2008 BART Analysis) which included an evaluation of retrofitting emissions control technologies to lessen the impact of Gerald Gentleman Station (GGS) on visibility at the Badlands National Park in South Dakota. The technologies considered in the 2008 BART Analysis were dry and wet Flue Gas Desulfurization (FGD) systems for SO₂ control and Low NO_x burners (LNB) and Selective Catalytic Reduction (SCR) for NO_x control. Sargent & Lundy (S&L) provided input to the 2008 BART Analysis by providing capital, O&M, and annualized cost estimates for the FGD and SCR technologies.

The 2008 BART Analysis did not include an evaluation of Dry Sorbent Injection (DSI) technology because it was not considered to be technically feasible for use at GGS. During the final comment period for the associated Nebraska State Implementation Plan (SIP) in 2010, the NDEQ received comments from the National Park Service suggesting that dry sorbent injection should be considered for application at GGS. At Nebraska Public Power District's (NPPD's) request, Sargent & Lundy prepared a letter dated January 6, 2011 that responded to the National Park Service comments. In that letter, Sargent & Lundy delineated the considerations that were used to eliminate DSI from being addressed in the 2008 BART Analysis and concluded that "DSI is currently not technically feasible for application for the source under consideration, Gentleman Station Units 1 and 2", and that "while ... an argument could be made that DSI is available for certain source type applications, it is not applicable to Gentleman Station".

The NDEQ disagreed with S&L's conclusion. In February 2011, the NDEQ asked that a side-by-side comparison be performed of dry sorbent injection technology and the FGD technologies, including both a cost comparison and a visibility impact comparison. Although S&L still believes that DSI is not technically feasible as previously stated in our January 6, 2011 letter, as requested by NPPD, we proceeded to prepare the cost comparison, for what should be considered a hypothetical evaluation based on S&L's opinion of the "technical feasibility" of the DSI technology.

As detailed herein, this analysis identifies the hypothetical capital, O&M, and annualized costs of applying dry sorbent injection technology at GGS. The analysis is based on both publicly available data and S&L expertise related to DSI. The visibility improvement and effectiveness will be modeled by HDR. HDR performed the same modeling used in the 2008 BART Analysis.

2.0 Evaluation Methodology

The evaluation of DSI technology for the purpose of developing cost estimates for SO₂ reduction at GGS was based on the following:

- Selection of a "target" stack SO₂ emission rate
- Selection of a sorbent type for reduction of SO₂
- Selection of a sorbent stoichiometric ratio based on the SO₂ removal efficiency needed

Once the appropriate performance parameters were established, design of the system could be approximated and the sorbent consumption and waste production rate could be calculated. The capital and O&M costs could then be determined. The final step was to convert the capital and O&M costs into an annualized cost estimate such that the technologies could be compared on an equal basis. This approach is further explained in the following sections.

2.1 Selection of “Target” Stack SO₂ Emission Rate

DSI technology has demonstrated the capability of removing moderate amounts of SO₂. However, DSI has not demonstrated that it can remove as much SO₂ as conventional wet or dry utility grade FGD technologies. In the 2008 BART Analysis, the candidate FGD technologies (conventional wet limestone and lime spray dryer) were evaluated as being able to reduce SO₂ emissions to less than 0.15 lb/MMBtu for coals having as much as 2.27 lb SO₂ /MMBtu. This sulfur content is representative of the high end of the sulfur content range for Powder River Basin (PRB) coals which are used exclusively at GGS. The evaluated reduction represents a removal efficiency of about 93%. S&L’s expectation for a cost effective application of the DSI technology would be at a considerably lower efficiency and a much higher resultant SO₂ emission rate.

From publicly available information, we are aware that a recent BART analysis prepared for Boardman Power Plant contained an evaluation of the use of DSI to lower emissions to 0.4 lb SO₂ /MMBtu subject to the results of pilot testing that would prove or disprove this capability. Also, it should be noted that the Boardman BART analysis for the use of DSI technology represented only 4-6 years of operation prior to closure of the Boardman Plant in the 2018-2020 time frame. This type of analysis criterion will tend to favor low capital and high operating cost technologies such as DSI.

Selection of a target SO₂ emission rate is based in part on the proposed DSI implementation for the Boardman Plant, which burns PRB coal and has a boiler/generating unit of similar size (584 MW) compared to the somewhat larger GGS generating units. The selection of the target SO₂ emission rate is also based in part on published theoretical projections by Solvay, a supplier of Trona and sodium bicarbonate sorbents which are candidate sorbents, for DSI applications. To present a side-by-side comparison of DSI and the FGD options used in the 2008 BART Analysis, S&L used the same design coal as for the dry and wet FGD options already evaluated as part of the 2008 BART Analysis. Based on the Boardman Plant DSI BART analysis and a very optimistic Solvay projection for control efficiency (approaching 80%) and using the design basis coal for GGS, we have selected an outlet (stack) SO₂ emission rate of 0.36 lb/MMBtu for this assessment. This is a more aggressive removal efficiency than proposed for Boardman where 0.36 lb SO₂/MMBtu would represent a removal efficiency of only 40%. Note that even with this relatively low efficiency for the Boardman BART, Portland General Electric requested flexibility in the ultimate emission limitation dependent on pilot testing. Without extensive GGS-specific modeling and actual field testing, and a contractual performance guarantee from a vendor, the analysis of DSI for GGS presented here must be considered theoretical.

2.2 Selection of Sorbent Type

Sorbents that can be used in the DSI technology include Trona, sodium bicarbonate, or lime. Sodium compounds (Trona and bicarbonate) are more reactive with SO₂ than is lime; therefore lime is rarely evaluated for SO₂ removal in DSI technology applications. Trona is more available than bicarbonate, but bicarbonate is more effective in that a pound of bicarbonate can remove more SO₂ than a pound of Trona. However, bicarbonate is effective in a more limited flue gas temperature range making it less flexible in the dynamic operating condition of a typical power plant. Finally, bicarbonate is more expensive.

Table 1 shows (1) the order-of-magnitude consumption rates for Trona and bicarbonate that would be needed for applications of the technology at GGS, (2) the relative costs of the sorbents, and (3) the domestic supplier’s production capacity.

Bicarbonate was not selected as the sorbent of choice for GGS for two reasons. First, bicarbonate needs to be injected into the flue gas stream within a tighter temperature range than Trona which would be a problem for GGS as will be discussed in the section of this report on stoichiometry. Second, GGS would consume

such a large portion of the current total market production capability that bicarbonate's availability to GGS would be in question. In addition, there are only three suppliers of bicarbonate so GGS would have little leverage on the suppliers and this situation would result in bicarbonate costs that would very likely escalate at a higher rate than other FGD sorbents, including limestone and lime. For these reasons, sodium bicarbonate is not considered to be an effective sorbent for the GGS units.

Table 1: Comparison of Consumption and Production Capacities for Trona and Bicarbonate

	Trona	Sodium Bicarbonate
GGs approximate consumption (million tons/yr)	0.6	0.5
Suppliers' production capacity (million tons/yr)	Solvay = 4.5 FMC = 4.0 Dwight = 4.0 Total = 12.5	Solvay = 0.15 FMC = 0.25 Dwight = 0.35 Total = 0.75
GGs' consumption as a percent of total suppliers' production capacity*	5%	67%
Price (\$/ton)	\$145 by rail	\$200 by rail

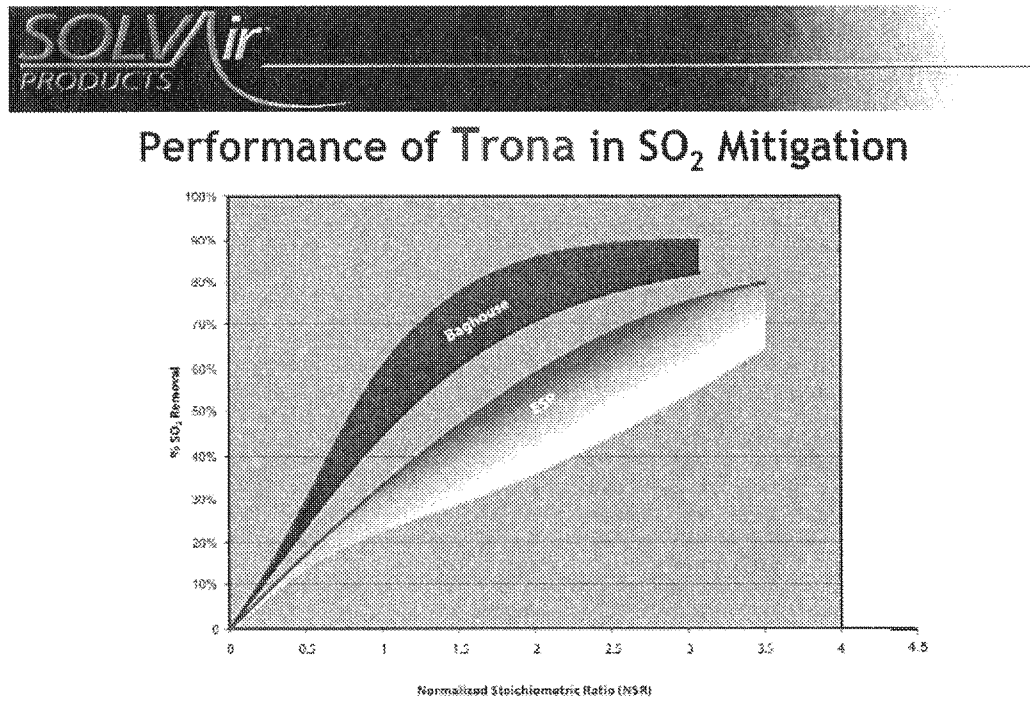
*Assumes the suppliers' production capacity of Trona and Bicarbonate is all available and does not figure in the amount already committed to others.

As can be seen from the Table 1, the current production of Trona comes from three suppliers and GGS would be consuming approximately 5% of the market. With only three suppliers competition would be low. This could create a higher rate of escalation in reagent price than what was used in this analysis. For comparison purposes, there are over 21 companies that produce lime (used in FGD technologies) and GGS would consume less than 1% of the lime market.

Trona is the sorbent type selected for this cost analysis.

2.3 Selection of Stoichiometric Ratio

After selection of a sorbent and an emission rate for GGS, the next step was to select a stoichiometric ratio to effectively deal with the selected emission rate. The normalized stoichiometric ratio is defined in the literature and represents the amount of Trona injected to remove a selected amount of SO₂. In the DSI industry, the stoichiometric ratio is correlated to removal efficiency and is usually presented in curves such as that shown in Figure 1. The curve in Figure 1 is publicly available and is presented frequently in DSI literature. However, the curves are very broad, which implies that their accuracy is limited. In other words, the curves show a general relationship between stoichiometric ratio and efficiency, but they are not so accurate that they could be used to define the stoichiometric ratio which would be specifically required at GGS. In addition, the curves are based mainly on industrial plant experience. Industrial plants perform significantly different from utility plants. In S&L's opinion, these curves must be viewed as optimistic projections that should only be used for general information. The only way to develop a meaningful stoichiometric ratio versus efficiency relationship specifically for GGS would be to conduct extensive modeling and field testing at GGS.

Figure 1: Normalized Stoichiometric Ratio versus SO₂ Removal Efficiency (From Solvay)

The relationship between Trona stoichiometric ratio and removal efficiency is highly dependent on the Trona particle size (milled versus un-milled), the flue gas temperature at the Trona injection location, the uniformity of injection across the ductwork, and the time of contact (i.e. residence time). Choosing the stoichiometric ratio is dependent on the aforementioned unit-specific parameters. As noted, the size of the Trona particle impacts the stoichiometric ratio and DSI suppliers have shown in recent tests that smaller, not larger, Trona particle sizes are more effective in capturing SO₂. However, smaller sized Trona particles cannot be shipped over long distances, therefore, the typical method of applying Trona is to deliver un-milled Trona to the site and then process it through an in-line mill that reduces the Trona particle size to about 20-25 microns. S&L used this approach in the GGS cost estimate analysis.

The flue gas temperature at the injection location impacts the stoichiometric ratio. The reaction of Trona relies on the ability of the SO₂ molecules to be captured in the pores of the Trona material. The more porous the material is the more sites that are available to capture SO₂ molecules. Trona has a characteristic that it will calcine ("popcorn") and become more porous when injected at temperatures between 275°F and 800°F. If it is injected at greater than 800°F or below 275°F, then each Trona particle is not as effective, and more Trona is needed, to collect a given amount of SO₂. The temperature profiles at GGS are not ideal (see discussion below) for this situation and, therefore, the Figure 1 curves do not accurately represent the stoichiometric ratio needed at GGS. In S&L's opinion, because much of the experience with this technology comes from industrial scale applications, the removal efficiencies shown by the curves are very optimistic for use at GGS.

Sorbent can be injected upstream or downstream of the unit's air preheaters. The GGS Unit 1 and Unit 2 temperature profiles upstream and downstream of the air preheaters were evaluated to determine the best injection location and the impact of temperature on stoichiometric ratio. The Unit 1 flue gas temperature downstream of the secondary air preheater is below 275°F for 74% of the operating hours. The temperatures upstream of the air heater are determined by the economizer outlet temperature. The Unit 1 economizer

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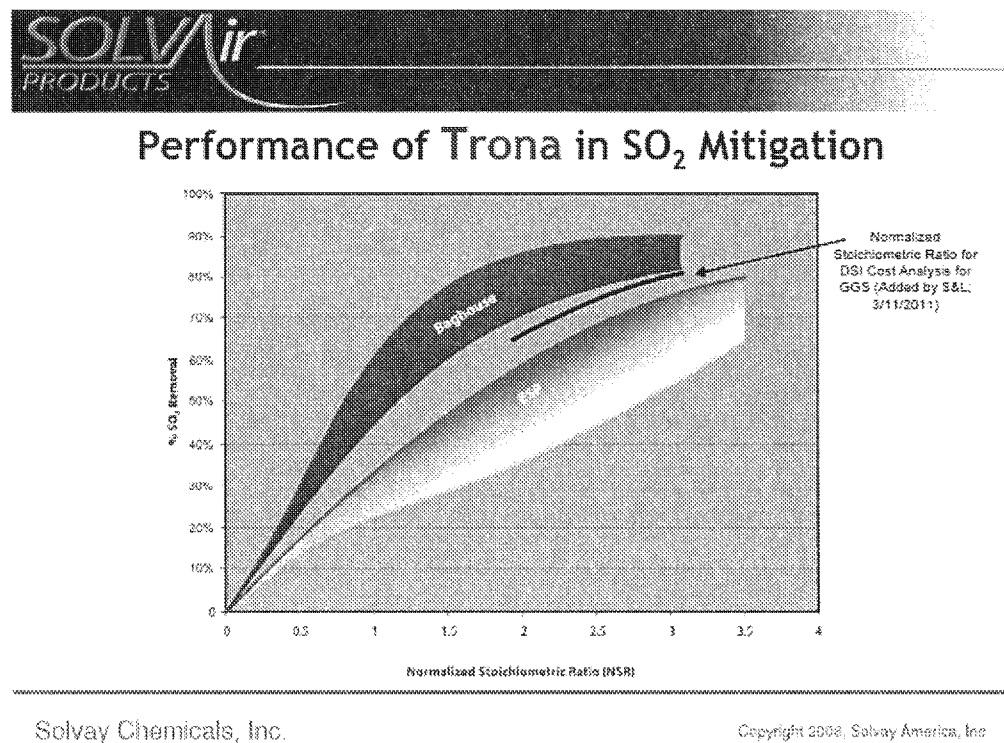
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outlet temperature is above 800°F for 29% of the operating hours and, if considering greater than 80% load, is above 800°F for 36% of the operating hours. The Unit 2 data indicates the temperature downstream of the secondary air preheater is below 275°F for 100% of the operating hours and the economizer outlet temperature is above 800°F for 25% of the hours. Therefore, both units have a poor temperature profile and the required stoichiometric ratio would be greater than shown in Figure 1 for any removal efficiency.

Finally, because much of the experience with this technology comes from industrial scale applications, the expectation for both removal efficiency and stoichiometry shown on this curve should be considered very optimistic for the large utility boiler systems at GGS.

The stoichiometric ratio relationship selected by S&L for this analysis for the GGS units is shown in Figure 2. This relationship is superimposed over the Solvay curve in Figure 1.

Figure 2: Normalized Stoichiometric Ratio versus SO₂ Removal Efficiency for GGS



2.4 Capital Cost Estimate Determination

The basis of the cost estimates used in this analysis is the same as that used in developing the costs for the 2008 BART Analysis, with one exception: The initial startup date for the technologies is now calendar year 2016 rather than 2013. The costs from the 2008 Analysis and this analysis of the DSI technology have been annualized for startup in 2016 and this change puts all technologies on the same economic basis. This change is necessary to allow time for the dry and wet FGD technologies to be built on an achievable schedule, rather than expecting they could be installed and made operational two years from the present, which is not achievable. The change to the startup date required that the FGD costs be escalated such that the first year of operation is 2016, rather than the 2013. The capital for the DSI technology also uses 2016 as the initial operation date and includes escalation.

The capital costs are presented as several components (construction direct, other construction, indirect, etc...) as shown in Exhibit 1. The DSI application for each Unit is designed for 87,500 lbs/hr (which represents the selected stoichiometry) and includes milling equipment, as previously described.

The direct construction components shown were developed using S&L in-house cost information. The capital cost estimate for the DSI application includes rail unloading, storage, transfer, milling, and injection subsystems. In addition to the DSI system cost estimate information, Exhibit 1 shows direct construction costs for rail upgrades to allow for receiving of Trona on site and includes costs for expanding the ash storage system due to the increased quantity of solid waste from the spent Trona. The rail upgrades and ash storage upgrades were also included in the FGD system cost estimates for the 2008 BART Analysis when appropriate.

The remainder of the capital cost components were added using the same bases that were used for the previously submitted FGD capital costs, with one exception: The contingency for this DSI application capital cost estimate uses 30% contingency (vs. 20% used in the FGD cost estimates) because the DSI order-of-magnitude costs were developed with minimal engineering analysis as compared to the detailed analysis performed for the 2008 BART Analysis.

2.5 O&M Cost Determination

Because it proved not to be practical to develop a true side-by-side comparison of the FGD and DSI technologies for GGS, the O&M costs were developed for a hypothetical case of reducing SO₂ emissions from the design coal used for the 2008 BART Analysis to meet an emission limit of 0.36 lb/MMBtu. This case is hypothetical because: 1) there are no precedents in the electric power industry of application of DSI to a boiler of this size and type, 2) there are no GGS-specific field modeling trials and testing of either Unit which have different designs and different boiler manufacturers, and 3) there are no contractual performance guarantees for GGS. Because it is unknown whether the DSI technology could meet this emission level in the case of GGS, such an application would, by definition, be hypothetical and experimental in nature.

The O&M cost estimate for the DSI implementation as described above is detailed in Exhibits 2a and 2b, and includes the calculation of the first year O&M cost and the annualized O&M cost for each unit, respectively. Consistent with the 2008 BART Analysis, a 20-year amortization period was used for the DSI system. The cost of the reagent and waste disposal are the predominant annual operating costs for the DSI technology. A new landfill cost is included in this evaluation because a new landfill would be needed for the DSI technology waste. The landfill includes costs for site preparation, placement of low permeability soil, installation of a geomembrane, and placement of a protective cover for closure of the landfill.

The DSI application will have an impact on the operation of the baghouse. The significant increase in the solids loading to the baghouse will require the bags to be cleaned more frequently. Bag cleaning frequency has a direct impact on the life of the bag. The increased cleaning frequency will lessen the bag life by 10% to 20%.

2.6 Annualized Cost Determination

Exhibit 3 presents the annualized costs for the FGD technologies as presented in the 2008 BART Analysis. As previously addressed, these costs were based on a 2013 operating date which is no longer reasonable. Therefore, Exhibit 3 also presents the same FGD costs escalated to calendar year 2016 to accommodate a normal engineering, construction and startup schedule. The exhibit also includes the DSI cost estimates for each option considered escalated to 2016.

The data in Exhibit 3 is close to the side-by-side comparison that NDEQ requested, but is based on a DSI outlet SO₂ emission rate of 0.36 lb SO₂ /MMBtu, not the 0.15 lb SO₂ /MMBtu value used for FGD technologies. Evaluating the DSI technology at an outlet loading of 0.15 lb SO₂/MMBtu and a corresponding SO₂ removal of 91% would represent an extrapolation of available data well beyond practicality. Even when evaluated at a lower removal efficiency and a higher outlet loading, the DSI technology annualized cost (\$/yr) and normalized cost (\$/ton SO₂) is higher than the FGD cost from the 2008 BART Analysis.

3.0 Other Retrofit Impacts

3.1 Energy Usage

The DSI application is expected to consume about 0.1 kW of the station's power for every 1 lb/hr of sorbent feed. For both units at full capacity, this equates to 16 MW, which is 1.2 % of the stations gross capacity. Most of the power is consumed by pneumatically handling the Trona, cooling the transport air, and keeping the stored Trona dry. The dry and wet FGD technologies consume 1.9 % and 2.7 %, respectively, of the station's gross power.

3.2 Disposal of Liquid

The DSI application does not use water to improve the mass transfer of SO₂ as is the case with dry and wet FGD technologies. The FGD technologies consume between 1,700 and 2,200 gpm of water.

Some water is used in DSI application to wash the Trona mills as a part of required daily maintenance. The Trona mills are filled with water to dissolve the deposits of sodium that accumulate on the mill internals. The water used for this purpose averages less than 10 gpm on an annual basis. The resulting liquid waste is high in sodium and, therefore, must be properly disposed of.

3.3 Potential Fugitive Emissions

The DSI application will have the potential to generate fugitive emissions as the dry sorbent is pneumatically transferred from the rail cars to the storage silos, from the storage silos to the day silo, and from the day silo to the injection subsystems. In addition, the rail delivery generates fugitive emissions while the sorbent is in transit. Finally, the handling of the baghouse waste streams have the potential to generate fugitive emissions as they are pneumatically transferred to the waste silos and unloaded to haul trucks. Also, since the solid waste generation rate associated with the DSI application will be about 3 times the current solid waste quantity, there will be three times the amount of haul truck traffic which will also increase fugitive emissions. All of these solids handling systems have the potential to increase fugitive dust emissions and must be controlled with additional dust control hardware and systems which increase both the capital requirement and O&M requirement.

4.0 Conclusion

It remains S&L's judgment that the DSI technology has not been proven on any power plant the size of the GGS units and, therefore, should not be considered "technically feasible" as the term is defined in the Regional Haze rule. Even so, as requested by NPPD, S&L developed the cost estimates for the application of the DSI technology on both GGS units to be as close to a side-by-side comparison to the previously analyzed dry and wet FGD technologies as is practical and reasonable.

Although the initial capital requirement for a DSI system at GGS is considerably less than that required for either of the FGD technologies evaluated in the 2008 BART Analysis, the operating costs for the DSI system

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at GGS, over the 20 year amortization life, resulted in an annualized cost of nearly 34% greater for the DSI system. Also, the cost to capture a ton of SO₂ with the DSI system is over twice as expensive as that required with either of the FGD technologies evaluated in the 2008 BART Analysis.

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EXHIBIT 1
Dry Sorbent Injection Capital Cost

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	GGG Unit 1	GGG Unit 2
Construction Direct		
Rail Unloading, Tracks and Switches	\$ 1,995,000	\$ 1,995,000
New Waste Silos	\$ 4,676,000	\$ 4,676,000
DSI System	\$ 35,960,000	\$ 35,960,000
Other Construction		
Engineering and Construction Management (5%)	\$ 2,132,000	\$ 2,132,000
Per Diem, Premium (5%)	\$ 2,132,000	\$ 2,132,000
Profit (10%)	\$ 4,690,000	\$ 4,690,000
EPC Fee (20%)	\$ 10,317,000	\$ 10,317,000
Total Construction	\$ 61,902,000	\$ 61,902,000
Indirect		
Owners Engineer	\$ 500,000	\$ 500,000
Bond Fees (2.5% of first \$200,000,000)	\$ 2,500,000	\$ 2,500,000
Owners Cost (2%)*	\$ 2,944,000	\$ 2,944,000
Escalation	\$ 5,091,000	\$ 5,091,000
Sales Tax (5.5% equip/material)	\$ 1,362,000	\$ 1,362,000
Contingency (30%)	\$ 21,882,000	\$ 21,882,000
Total Project Cost	\$ 96,181,000	\$ 96,181,000
AFUDC	\$ 7,984,000	\$ 7,984,000
GRAND TOTAL COST (\$2016)	\$ 104,165,000	\$ 104,165,000

Notes:

* Includes 2 weeks of sorbent injection testing.

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EXHIBIT 2A
Budgetary DSI O&M Cost Estimate (per Unit)

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Dry Sorbent Type		Trona
Design Removal Efficiency		80% SO ₂ Removal
Particulate Collector		Baghouse
Input Data for System Analysis:		
Fuel		PRB
Gross Capacity	MW	745
Capacity Factor	%	80
Heat Input to Boiler at Full Load	MMBtu/hr	7,047
Fuel Heating Value	Btu/lb	8,124
Fuel Sulfur Content	lb/MMBtu	1.72
Fuel Ash Content	%	5.42
Ash Removal in Boiler	%	30.00
Dry Sorbent Injection Analysis:		
Dry Sorbent Requirement	lb/hr	87,500
Dry Sorbent Requirement	t/yr	383,250
Dry Sorbent Consumption	lb/hr @ CF	70,000
Dry Sorbent Consumption	t/yr @ CF	306,600
Waste Disposal Analysis:		
Flyash Production (Leaving the Boiler)	lb/hr	32,910
Sorbent Waste Rate	lb/hr	67,495
Total Waste for Disposal (Ash + Sorbent)	lb/hr	100,405
Total Waste for Disposal (Ash + Sorbent)	t/yr	439,775
Total Waste for Disposal (Ash + Sorbent)	t/yr @ CF	351,820
Auxiliaries Analysis:		
Increase in Auxiliary Power Consumption - Full Load	kW	8,750
Economic Parameters:		
Total number of Bags		16,474
Replacement Bag Cycle	years	6
Bag Replacement Cost	\$/bag	172.00
Dry Sorbent Cost	\$/t	145.00
Waste Disposal Cost	\$/t	5.64
Revenue from Flyash Sale	\$/t	1.35
Power: Energy Charge (Auxiliary Power)	\$/MWh	45.65
Power: Capacity Charge	\$/kW/year	46.00
Labor Rate	\$/hr	40.60
Variable O&M Cost:		
Bag Replacement Cost	\$/yr	\$ 473,000
Dry Sorbent Cost	\$/yr	\$ 44,457,000
Waste Disposal Cost	\$/yr	\$ 1,984,000
Revenue from Flyash Sale	\$/yr	\$ -
Power: Energy Charge Cost (Auxiliary Power)	\$/yr	\$ 2,800,000
Power: Capacity Charge	\$/yr	\$ 402,500
SO ₂ Allowance Sale	\$/yr	\$ (1,016,000)
Total Estimated Variable O&M Cost	\$/yr	\$ 49,100,500
Fixed O&M Cost		
Additional Operating labor	no.	4.5
Additional Operating labor	\$/yr	\$ 382,000
Additional Maintenance Material	\$/yr	\$ 240,000
Additional Maintenance Labor	\$/yr	\$ 360,000
Additional Administrative labor	\$/yr	\$ -
Total Estimated Fixed O&M Cost	\$/yr	\$ 982,000

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EXHIBIT 2B
Budgetary DSI Annualized O&M Cost Estimate

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Dry Sorbent Type Design Removal Efficiency Particulate Collector		Trona 80% SO ₂ Removal Baghouse	
Annualized Variable O&M Cost:			
Bag Replacement Cost	\$/yr	\$	578,000
Dry Sorbent Cost	\$/yr	\$	54,238,000
Waste Disposal Cost	\$/yr	\$	2,421,000
Revenue from Flyash Sale	\$/yr	\$	-
Power: Energy Charge Cost (Auxiliary Power)	\$/yr	\$	3,416,000
Power: Capacity Charge	\$/yr	\$	492,000
SO ₂ Allowance Sale	\$/yr	\$	(1,240,000)
Total Estimated Annualized Variable O&M Cost	\$/yr	\$	59,905,000
Annualized Fixed O&M Cost:			
Additional Operating labor	\$/yr	\$	467,000
Additional Maintenance Material	\$/yr	\$	293,000
Additional Maintenance Labor	\$/yr	\$	440,000
Additional Administrative labor	\$/yr	\$	-
Total Estimated Annualized Fixed O&M Cost	\$/yr	\$	1,200,000
TOTAL ESTIMATED ANNUALIZED O&M \$2011	\$/yr	\$	61,105,000
TOTAL ESTIMATED ANNUALIZED O&M TO 2016\$	\$/yr	\$	69,135,000

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EXHIBIT 3
Modification of Table 4 from 2008 BART Analysis, SO₂ Cost of Compliance

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Description	Technology Options		
	Dry FGD	Wet FGD	Dry Sorbent Injection
Emission Rate (lb/MMBtu)	0.15	0.15	0.36
Emission Reduction (tpy)	39,815	39,815	25,857
Capital Costs (\$)	\$ 981,592,000	\$ 1,029,819,000	
Annualized Capital Cost (\$)	\$ 80,013,000	\$ 83,965,000	
Annualized Operating Cost (\$)	\$ 27,806,000	\$ 24,485,000	
Annualized Outage Cost (\$)	\$ 698,000	\$ -	
Total Annualized Cost (\$)	\$ 108,517,000	\$ 108,450,000	
Normalized Cost (\$/ton SO ₂ reduced)	\$ 2,726	\$ 2,724	

Escalation factors to convert the above Table 4 to the below revised Table 4

Capital Escalation Rate (%)	2.5%	2.5%	
O&M Escalation Rate (%)	2.5%	2.5%	
Years of Escalation (#)	3	3	

Theoretical Normalized Stoichiometric Ratio			3.0
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The above Table 4 but Escalated to 2016 1st year operating date (total for both Units)

Emission Rate (lb/MMBtu)	0.15	0.15	0.36
Emission Reduction (tpy)	39,815	39,815	25,857
Capital Costs (\$)	\$ 1,057,068,000	\$ 1,109,003,000	\$ 208,330,000
Annualized Capital Cost (\$)	\$ 86,166,000	\$ 90,422,000	\$ 17,500,000
Annualized Operating Cost (\$)	\$ 29,945,000	\$ 26,368,000	\$ 138,270,000
Annualized Outage Cost (\$)	\$ 752,000	\$ -	\$ -
Total Annualized Cost (\$)	\$ 116,863,000	\$ 116,790,000	\$ 155,770,000
Normalized Cost (\$/ton SO ₂ reduced)*	\$ 2,935	\$ 2,933	\$ 6,024

* Calculated based on the maximum actual 24-hour SO₂ emissions realized over the 3-year baseline period (2001-2003) that was used in the 2008 BART Analysis.

APPENDIX B

APPENDIX B

Gerald Gentleman Station
Modeling Scenarios for BART Analysis (Added DSI scenario in gray)

Control Description		2-Unit Hrly Maximum 24-h avg. actual heat input* (MMBtu/hr)	2-unit avg SO ₂ E.F. (lb/mmBtu)	2-unit avg NO _x E.F. (lb/mmBtu)	2-unit avg Filterable** PM E. F. (lb/mmBtu)	TOTAL Emissions Both Units			Stack Parameters***	
						SO ₂ (g/sec)	NO _x (g/sec)	PM ₁₀ (g/sec)	Temp. (deg. K)	Vel. (m/sec)
SO ₂	PM									
no control	FF	15175.5	0.749	0.455	0.00823	1412.87	869.51	6.14	35.11	417.05
no control	LNB/OFA	15175.5	0.749	0.23	0.00823	1412.87	439.79	6.14	35.11	417.05
DSI	FF	15175.5	0.36	0.455	0.00823	688.36	869.51	6.14	35.11	417.05
SDA	LNB/OFA	15175.5	0.15	0.23	0.00823	286.82	439.79	6.14	35.11	352.04
SDA	LNB+SCR	15175.5	0.15	0.08	0.00823	286.82	152.97	6.14	35.11	352.04
SDA	none	15175.5	0.15	0.455	0.00823	286.82	869.51	6.14	35.11	352.04
no control	LNB/OFA+SCR	15175.5	0.749	0.08	0.00823	1412.87	152.97	6.14	35.11	417.05

* Maximum daily heat input for baseline period, occurring in 2001. "No-control" SO₂ and NO_x emission factors are estimated values for maximum 24-hour emission days.

** Filterable emission factor based on stack tests after FFs installed.

*** Slightly more conservative (lower) velocity of the two stacks to be used in the modeling.

Condensable PM emissions assumed to be 0.014 lb/mmBtu, based on AP-42 and 0.44% sulfur, and are assumed to form only PMF.

PMF for fabric filter is 39% of total filterable PM, per AP-42

PMF for fabric filter is 53% of total filterable PM plus 0.014 lb/mmBtu condensables, per AP-42